Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2010_29 Curtailable Loads and Demand Side Programs

Submitted by

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Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

EnerNOC has previously commented on the changes proposed within RC_2010_29. Our comments within this submission are focused upon those areas of contention within the proposed rule changes. In brief, however, we support and propose no amendments to the suite of changes being proposed under the following Issue headings:

- Issue 1: Registration of Curtailable Loads
- Issue 2: Facility Definition
- Issue 3: Market Fees
- Issue 6: Reserve Capacity Security
- Issue 7: Stipulated Default Loads
- Issue 8: Potential Double Payment

With regards to Issue 5: Capacity Cost Refunds, EnerNOC supports the IMO's proposed amending rules, specifically 4.12.4(c)v, which limits a Demand Side Programme's (DSP) Reserve Capacity Obligation Quantity to those intervals within which the DSP has outlined its availability. We also agree with the IMO's approach to clarify and make accurate the intent of forced outage refunds through the introduction of the term "Facility Reserve Capacity Deficit Refund".

ISSUE 4: MEASUREMENT OF CL PERFORMANCE

Dynamic vs Static Methodologies

The IMO has requested stakeholder views during this second submission period on the issue of whether a static or dynamic Relevant Demand (RD) methodology should be adopted.

From the outset, EnerNOC believes it is important for the Wholesale Electricity Market (WEM) to clarify and confirm the intent of the RD methodology within the market. Not only is this clarification useful to help frame the discussion about the methodology best suited to achieve the purpose of the RD, but it is also important as some of the submissions in response to EnerNOC's concept paper (PRC_2011_01) appeared to incorrectly assume that the RD serves multiple purposes.

To be clear, the RD measure is an *operational* tool and should not be confused with other determinants used within the WEM for system *planning* purposes. The specific intent of the RD measure is to quantify the immediate forecast and post-event delivery of Demand Side Management (DSM) capacity managed by DSPs. As such, the RD measure should be designed to *reflect the normal operating profile during all intervals when the DSP is forecast to be, or was, dispatched*.

Confirming the intent of the RD measure in this way helps clarify that the purpose of the methodological design comprising the RD is to enable as accurate as possible a measure for DSP *output (curtailment)*, in a similar fashion to measures that may be used to determine accurate generator output. By adopting this intent and parallel with generation resources, further clarity is provided with regards to the *operational* nature of the RD – measures used to quantify generator output do not support system planning needs but simply operational concerns only.

It is EnerNOC's position that demand response and generation should be treated comparably. For generation, capacity amounts to a call option on a specific amount of energy under certain pre-defined circumstances. Where demand response is providing capacity alongside generation, so should it be for demand response; a MW of capacity should equate to the ability to deliver (or in this case, make available by not consuming) a MW of energy. What matters for demand response should be, as the name suggests, how much demand actually *responds* by decreasing its usage in real time.

The operational function of the RD measure lends itself to investigation and a determination of any changes to the existing methodology independent of any proposed considerations relating to the entire Reserve Capacity Mechanism (RCM). That is, regardless of the outcome of potential amendments to the RCM that may arise from the review process currently underway, it is incumbent upon the IMO to determine a measure that accurately reflects DSP performance independently of other considerations such as how demand side resources may initially enter the RCM or the Availability Classes that such resources must be subject to.

EnerNOC has previously outlined a concept paper (PRC_2011_01) detailing its support for the development of a profile baseline RD methodology to replace the existing static RD approach. Without restating much of that case, in summary we believe the adoption of a profile baseline RD methodology – a methodology that maps load profiles and changes dynamically to reflect recent conditions and consumption patterns – will provide significant benefits for the WEM:

- **Accuracy**: static baselines, like the current RD design, trade accuracy for simplicity. A static RD measurement that uses consumption data from as much as a year in the past and which does not change to reflect differences in a load's profile over the course of a day, week, or season is inherently inaccurate and inappropriate for system operational purposes. A static RD simply cannot provide insight into whether or not a DSP has load reduction capabilities at the specific time SM may need them, nor can it be counted on to provide an accurate assessment of a DSP's performance after a dispatch. By contrast, a dynamic profile measure that utilises the latest information about a load's consumption behavior and capabilities, and incorporates adjustments to account for the type of conditions experienced on the day in which a DSP is dispatched, has clear benefits to offer in terms of the accuracy of the measurement of a DSPs performance;

- **Alignment of Performance Incentives**: a significant drawback with the use of a static RD measure relates to the inefficient and confused incentives it provides to DSPs and their respective end-user loads. As a flat measure based upon last year's peaks, a static RD rewards incidental performance – where a load is already operating below their baseline and receives credit for greater levels of demand reduction than what actually took place – while simultaneously penalising actual curtailment that is undertaken by loads that sit above their RD when dispatched by not recognising this "above RD" curtailment quantity. A dynamic baseline seeks to record DSM capacity provision by any load based upon their consumption level on the day of the dispatch, thereby correcting the incentive structure and rewarding actual DSM capacity provision and not any incidental or phantom curtailment.

- **Reliability**: by enabling greater accuracy and predictability, a dynamic baseline significantly improves the reliability of forecast DSM capacity in a manner that is consistent with other capacity sources. By removing the inaccuracies associated with incidental performance under a static baseline, a dynamic profile methodology helps system reliability by avoiding potential overestimations of available DSM capacity which could lead to SM inadvertently allowing more outages than should be permitted to maintain reliability standards.

- **Visibility**: DSPs utilising dynamic baselines require greater visibility of their portfolio loads to enable effective management in the delivery of their DSM capacity. This is likely to lead to more widespread real-time monitoring of constituent loads which could assist SM's visibility of DSP performance and provide more efficient dispatch instruction arrangements as a result of this improved visibility.

Since releasing our concept paper in February 2011, several comments have been received in relation to the proposition of moving towards a dynamic profile baseline. In response to these comments, we make the following brief observations:

- **Sustainability of DSM**: contrary to any commentary that might imply that EnerNOC seeks to utilise a dynamic baseline approach to simplify or make easier our provision of DSM capacity, the opposite is in fact true. We have not conducted any analysis upon our existing portfolio to determine any *net capacity benefit* that might be obtained through adopting a dynamic measure. Indeed, we firmly believe such adoption would make DSM capacity provision more challenging than is currently the case, and our unparalleled experience operating in other markets under both static and profile baseline measures, including past quantitative analyses on DSM portfolios in other markets, supports this view. Our intent in moving forward with the proposal is to secure the long term sustainability of DSM resources within the WEM by adopting accurate performance measures and thereby ensuring that the WEM can count on the value of DSM resources within an operational context far into the future;

- **Capacity obligations**: switching the RD calculation from a static measure to a dynamic profile methodology will only impact the measurement of DSP performance and will not look to change other aspects of DSM participation in the RCM. Static requirements such as the quantity of capacity credits assigned to any individual DSP will not fluctuate under a dynamic baseline as some appear to believe. All that will change is that DSPs will be required to physically provide what they've been paid for by the WEM, and are not simply able to meet performance standards via incidental or phantom performance. In this manner, the commitments of DSPs – their availability and associated Reserve Capacity Obligation Quantities – will very much remain under the dynamic baseline proposal, as will the level of capacity payments received. Rather the proposed changes seek only to amend *how performance is measured* against these static requirements;

- **Nature of the Capacity Market**: concern has been expressed that the two year forward nature of the RCM makes the use of a dynamic RD either unworkable or less attractive than a static measure. This concern betrays confusion between the planning requirements embedded within the RCM and the operational needs of system managers. Were the logic extended, it might be argued that the RD measure would need to be fixed more than 2 years in advance of delivering DSM resources, making a mockery of DSP performance measurement. Moreover, the concern fails to recognise that other liberalised electricity markets with significant demand response penetration, such as ISO New England and PJM Interconnection in the United States, combine forward capacity markets with dynamic profile baseline DSM measurement approaches;

- **Sufficient Arrangements at Market Start**: it has been argued that a dynamic baseline would make it more difficult for the IMO to ensure a DSP provider has sufficient arrangements in place at market start to deliver upon their capacity commitments. EnerNOC previously encountered similar arguments in the US market of ISO-New England where the DSM baseline is a dynamic one. Yet, ISO-NE now has the highest percentage penetration of demand response of any liberalised market in the United States. EnerNOC believes compliance under an inaccurate static measurement scheme may be easier to determine, however, it provides little reassurance of a DSP's *actual* capability to provide capacity when dispatched by SM. Moreover, we hold that such "static" registration requirements can easily accommodate a dynamic baseline measurement through adopting approaches such as individual load curtailment nominations, periodic meter data audits, and/or utilising existing verification processes;

- **Reliability of security of supply forecasts**: following on from the concern relating to whether the IMO can determine that sufficient DSM capacity is in place to meet capacity obligations, a fundamentally flawed argument has been made to suggest a dynamic baseline would impact the IMO's security of supply forecasts. The reverse is very much the case, as a dynamic baseline does not create uncertainty as to whether the DSP provider has sufficient capacity, but actually increases the confidence that they truly have the ability to provide the capacity they are obligated to, and that meeting this commitment has not been undertaken through phantom loads and incidental performance. In reality, a dynamic baseline provides additional confidence to the IMO's security of supply forecast, since it can forecast the true ability of a DSP to provide capacity when dispatched by SM. As such, it is our strong contention that those Market Participants that voice concern about the availability and reliability of DSM should consequently be the strongest advocates for a more accurate profile baseline approach, and not cling to a flawed static one that may only provide the appearance of compliance with capacity obligations.

EnerNOC welcomed and supported the IMO's approach to conduct a stakeholder workshop on the issue of a static versus dynamic RD measurement, held on 8th April 2011. We believe the feedback received during the workshop indicated widespread and wholesale support from market participants for adopting a dynamic RD measurement and moving away from the existing static approach. We recognise that further analysis and discussion are required prior to adopting any particular type of dynamic baseline and we look forward to actively participating in this process.

RD Interval Alignment with IRCR Intervals

The IMO's current proposal within RC_2010_29 is to amend the RD measurement such that the intervals used match those intervals currently utilised for determining a market customer's Individual Reserve Capacity Requirement (IRCR).

EnerNOC acknowledges Data Analysis Australia's work which suggests the IRCR intervals may better reflect the likely level at which a load will be operating at during a peak demand event during the next year. We do not dispute the veracity of the analysis but only restate our position that a dynamic RD measure would be a significant improvement over any form of static methodology, the consideration of which was outside the scope of DAA's investigation.

In its response to comments received during the first submission period, the IMO states that a DSP's RD and a market customer's IRCR are interrelated[1]. EnerNOC does not view the two measures as requiring or having any relationship whatsoever. A DSPs RD measure should be designed to accurately calculate the quantity of DSM capacity provided by the DSP when dispatched, whenever this dispatch occurs and for whatever reason it occurs. The RD measure should be entirely independent of how the costs for capacity in the WEM are distributed amongst market customers that serve load, which is the purpose of the IRCR measure. Indications that the two measures are somehow interrelated might logically lead participants to deduce that there need also be a link between generator capacity measures (ratings at 41°C) and how capacity charges should be distributed amongst market customers. Clearly, and rightly so, no such linkage exists between generator capacity measures and the IRCR and it is argued that the same convention be heeded for measures to assess DSM capacity.

Proposals to link the RD measure to measures used to distribute costs for capacity within the market are fundamentally conflating what should be two separate and distinct measurement methodologies. How to measure what a DSP provides in terms of DSM capacity when dispatched has no relationship to how the costs of capacity should be distributed across market participants.

Moreover, how the costs of capacity are distributed to contributors of peak demand is a key and integral consideration of the RCM. With the current review of the RCM underway, and the concomitant potential for this key measurement to be part of any amendments to the RCM moving forward, in the interests of avoiding multiple changes to the RD in fairly quick succession (and assuming, for a moment, support for it be aligned to the IRCR as proposed under RC_2010_29), it is recommended that the existing RD remain in place until such time as it can, in order of priority, be replaced by a dynamic measure or clarity surrounding how capacity charges may be distributed within the WEM is available.

While we have not, for the sake of brevity, reiterated our previous arguments on the dangers of conflating the two measures, EnerNOC remains firm in its belief that the IMO's proposed approach to DSP performance measurement as outlined in the RC_2010_29 Draft Report will create significant risks for DSM capacity provision and lead to greater instability and higher costs for the market as a whole.

Separate and Independently Valuable Services: Peak Load Reduction & Dispatchable Capacity

It is recognised that the main consideration underlying the intent of the IMO in supporting an alignment between the RD and IRCR intervals is to remove the potential for what has been termed "double payment/counting" – where an NDL reduces its peak in the previous year and secures an IRCR cost reduction while utilising RD recalculation provisions to increase its capacity potential and therefore receive higher capacity payments.

EnerNOC believes that the ability for any individual NDL to provide an immediate system capacity service as well as a longer term capacity reduction service appears to be a philosophical argument that requires resolution within the WEM. We view our comments below as a first significant contribution to this debate and look forward to what we hope and understand may be an ongoing dialogue on this question.

As we have identified within other forums, there is a major inconsistency in the IMO's current approach. While arguing to remove the ability for a load to reduce its IRCR and then subsequently, due to maintenance and as part of a DSP, request to have its RD recalculated in order to "maximise" its capacity potential, the IMO has proposed that this exact capability be enabled for loads which provided a SM-dispatched capacity service coincidentally with IRCR intervals. Under the proposed new rule 4.26.2CC, where a DSP was operating at below capacity due to its consumption being reduced at the request of SM during one or more of the IRCR intervals, the IMO must set the RD based on its estimate of what the DSPs consumption would have been during those intervals.

In effect, the IMO is proposing that the provision of both services – dispatchable capacity and non-dispatchable peak load reduction – when provided coincidentally will be paid for by the market (independently and for both services), however, where these services are provided non-coincidentally no

[1] Draft Rule Change Report, Curtailable Loads and Demand Side Programmes, 18 March 2011, page 22 of 146.

such payment (or potential for payment) will be made available for the provision of dispatchable capacity. While we support the IMO's underlying proposition that a load called to provide capacity by SM should not face a future penalty or diminution in their capacity capabilities, we believe the flaw in the current logic of the IMO's proposal is self-evident.

Philosophically, EnerNOC believes dispatchable capacity and non-dispatchable (voluntary) peak load reduction are two separate and valuable system services that can be provided by loads and their associated DSPs.

It has been argued that a load which voluntary reduces its demand during system peak periods (IRCR intervals) signals to the market that it does not need capacity to be built to cover its actual capacity demand requirements for the rest of the year. These same arguments accept that this peak load reduction activity would be acceptable if the load did not, at any other time during the year, exceed the demand it attained during the peak 12 trading intervals. Linked with the above arguments are further suggestions that only a load which has paid for its capacity (via an IRCR charge) has the "right" to sell that capacity back to market as a DSM resource.

In response to these arguments, EnerNOC makes the following comments:

- It is indeed true that a load which reduces its IRCR may signal that a reduction in peak system capacity is also required. However, since overall capacity requirements are based upon complex forecasts and not simply the summation of all IRCRs, this is not a one-for-one reduction. Moreover, this reduction is a system benefit generated by a load undertaking voluntary actions. In fact, if practiced by enough customers, the overall load factor and efficiency of the entire system would be improved. It is because this benefit is generated by the reducing load that efficient payment mechanisms should ascribe the benefit to the participating load;

- It is not true to propose that this same signal is defective or inappropriate where a load exceeds its demand recorded during system peak intervals at other times during the year. System capacity requirements are properly determined around system peak requirements – planning measures for future system capacity correctly ignore load demands during non-peak periods. The WEM's winter peak, while potentially of interest to operational managers, has no bearing on the quantity of reserve capacity procured to enable reliability during the system's peak period of summer. Were this not the case, under this flawed argument loads that intelligently shift their peak demands to off-peak periods should be ascribed a higher capacity charge than they currently face, an absurd proposition;

- To artificially limit the amount of capacity a DSP can offer to the WEM based on its consumption during IRCR intervals, and irrespective of its actual ability to provide capacity when called upon by SM, diverges from the treatment generators receive and is inherently discriminatory against DSM resources. Consider that a generator's capacity value is directly related to the amount of energy it can supply to the system when called upon to do so. In this manner, on the supply side of wholesale markets, as noted earlier, capacity is nothing more or less than a call option on the associated energy. As it is with generation, so it should be with DSM.

EnerNOC strongly refutes arguments that suggest loads reducing their IRCR are somehow "free riders" and obtain a capacity subsidy from other end-users. This argument flies in the face of all accepted wisdom across energy markets globally that peak pricing signals are the most efficient method in distributing peak system costs to end-users. End-users who respond to peak pricing signals are, in fact, undertaking economically rational decision-making that one would be hard pressed to find a creditable market economist describing it as some form of rent-seeking. References to subsidies provided to loads who reduce their peak demands - when what is at issue is rewarding them with the marginal costs that they *save* the system — makes no sense at all except in an anti-competitive, purely static system of regulated monopoly utilities.

The significant point is that loads that voluntarily choose to curtail their usage at peak times (and even during some off-peak times) increase net social welfare as the economist defines it. The individual loads are better off as the value of peak load compensation outweighs any inconvenience in curtailing their usage, and all other loads are also better off because the peak curtailment reduces, or holds down, the incremental cost of continuing to serve all, while holding the possibility of losses of load and blackouts, highly injurious to all loads, to pre-determined optimal levels. Society also benefits by the voluntary reduction because it defers or entirely puts off the cost of constructing additional generating plant and/or conserves the characteristically heavy use of fuel by peaking generators.

In an industry subject to increasing costs, any and all efforts to promote curtailment in peak load demands on the system confer benefits upon all consumers, participants and non-participants alike, by diminishing the recourse of all suppliers to higher marginal cost generation. To do otherwise essentially invites customers to consume electricity with no concern about the increases in peak demand it might cause, thereby creating economic incentives that run directly counter to the interests of society as a whole.

Providing Dual Services

A load's past attempt to manage IRCR exposure has no bearing on the current demand reduction that the same load can provide when called upon to do so by SM. Underlying any concepts of aligning IRCR and RD intervals is an assumption that because a customer managed their IRCR in the previous year that they can be assumed in the current year to have already curtailed or be likely to curtail demand when SM would otherwise dispatch them. EnerNOC contends this assumption is erroneous, and would lead to market inefficiencies, not to mention potential negative reliability implications.

It is also erroneous to argue that a load attempting to offer more demand response they can reduce when called upon by the SM is attempting "sell" more capacity than it has "purchased." The total amount of capacity acquired or "purchased" on behalf of all customers is completely unrelated to any and all customers' IRCRs. While it may be true than the customer has sought to sell more capacity than that which has been <u>allocated</u> to it, this is purely a cost allocation issue, not a reliability question, as some may argue.

As outlined previously, it is illogical to, on the one hand, support the conferring of a capacity charge reduction benefit and a capacity payment benefit on a load when it is dispatched for capacity coincidentally during peak IRCR intervals, and then, on the other hand, suggest it is improper that the dual benefits are conferred upon the load when providing these services *at different times*.

As we have noted, peak load reduction and demand response are both laudable and harmonious undertakings that can and should coexist. EnerNOC supports incentives for loads to provide the dual services of dispatchable capacity provision and voluntary peak load reduction. We do not believe there are any clear arguments relating to economic efficiency to suggest that such dual provision of services by any one load, particularly when these services are provided at different times during the year, would lead to anything but a more efficient market outcome for all electricity users.

Recommendations

In relation to Issue 4, EnerNOC recommends that:

- The RD measure be amended to a dynamic profile baseline methodology;
- The IMO seek to undertake the necessary research and consultation required to develop a new dynamic RD methodology in a timely fashion and with a view for implementation during the 2012/13 capacity year;
- Prior to the required investigation and analysis needed to determine the most appropriate dynamic RD methodology, the existing RD measure remain in place.

2. Please provide an assessment whether the change will better facilitate the achievement of the Market Objectives.

EnerNOC has previously submitted its assessment on whether the changes proposed within RC_2010_29 better facilitate achievement of Market Objectives. For the purposes of completeness, we have reiterated these assessments below.

We consider the changes proposed by the IMO to amend the calculation of the Relevant Demand to be based on the aggregated output of the DSP (portfolio-basis), together with the ability to oversubscribe DSPs will have the following impact on the Market Objectives.

Impact	Market Objectives
Allow the Market Rules to better address the objective	a, d, b
Consistent with objective	c, e
Inconsistent with objective	

EnerNOC considers the changes proposed to amend the calculation of the Relevant Demand to be calculated on the IRCR intervals will have the following impact on the Market Objectives:

- Promote unreliability in the supply of capacity in the South West interconnected system by utilising an inaccurate RD measure, and impacting DSM capacity supplies;
- Work against the provision of economically efficient electricity related services in the SWIS by forcing a choice between peak load reduction services or capacity provision;
- Introduce discrimination against particular energy options and technologies that reduce overall greenhouse gas emissions;
- Increase the long-term cost of electricity supplied to customers from the South West interconnected system; and
- Discourage the taking of measures to manage the amount of electricity used and when it is used.

Impact	Market Objectives
Allow the Market Rules to better address the objective	
Consistent with objective	b
Inconsistent with objective	a, c, d, e

EnerNOC considers the changes it has recommended to amend the RD measure towards a dynamic profile baseline will have the following impact on the Market Objectives:

- Promote greater reliability and efficiency in the supply of electricity and electricity related services in the South West interconnected system;
- Encourage the efficient entry of new competitors to the WEM;
- Helps avoid discrimination against particular energy options and technologies that reduce overall greenhouse gas emissions;
- Better assist with minimising the long-term cost of electricity supplied to customers from the South West interconnected system; and
- Maintain the encouragement of measures to manage the amount of electricity used and when it is used.

Impact	Market Objectives
Allow the Market Rules to better address the objective	a, c, d, e
Consistent with objective	b
Inconsistent with objective	

EnerNOC considers the changes proposed to Capacity Cost Refunds (Issue 5) by amending rules, specifically 4.12.4(c)v, which limits a DSPs Reserve Capacity Obligation Quantity to those intervals within which the DSP has outlined its availability, will have the following impact on the Market Objectives:

- Avoid discrimination against particular energy options and technologies by enabling refunds to be paid in relation to agreed Availability requirements only.

Impact	Market Objectives
Allow the Market Rules to better address the objective	c
Consistent with objective	a, b, d, e
Inconsistent with objective	

3. Please indicate if the proposed change will have any implications for your organisation (for example changes to your IT or business systems) and any costs involved in implementing these changes.

Changes to the static RD measurement calculation will have an impact on EnerNOC as we will need to amend existing systems containing the current static measurement approach. We envisage the costs associated with this change to be small.

Alignment of the RD measure with IRCR intervals, as proposed by the IMO, will have an impact on EnerNOC's portfolio management. We forecast that existing and new DSM-capable loads are likely to target their IRCR charges, reducing capacity potential from these loads and/or preventing some customers from being able to deliver demand response capacity to the WEM as originally planned. Such results would also potentially impact the ability to recruit sufficient capacity, as capacity obligations were taken on when the Market Rules would not have impacted the ability for customers that manage their IRCR exposure to participate in the WEM. It is unclear at the present time what the precise magnitude of the impact will be, however, it is expected to be significant.

By increasing the risk of capacity overestimation in the WEM, as well as reducing the size of the DSM market within WA, higher funding and operational costs for all Market Participants and end-users are envisaged.

4. Please indicate the time required for your organisation to implement the change, should it be accepted as proposed.

EnerNOC estimate that, were the changes as proposed by the IMO to proceed, it may take approximately 3 months to implement changes to the measurement calculation, with the main requirements of systems and contract changes requiring this period for implementation.

EnerNOC forecasts that longer term changes in the makeup and structuring of its DSM portfolio would also be likely. Portfolio construction requirements for the 2013/14 year are likely to be impacted, together with restructuring requirements for the 2012/13 year.